METHODOLOGY FOR ASSESSMENT OF TECHNICALLY RECOVERABLE RESOURCES OF COALBED GAS

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INTRODUCTION

Coal is the most abundant energy source in the world, with reserves estimated to be in the range of several trillion tons. In addition to minable reserves, coal is considered to be a source of hydrocarbons, in particular natural gas. The presence of methane-rich gas in coal has long been recognized because of explosions that occur during underground mining, creating production problems and danger to human life. Only recently has gas in coal beds been recognized as a large untapped energy resource: coal serves as both the source and reservoir rock.

The natural gas resource base of the United States is estimated to be very large and diverse (National Petroleum Council, 1992). In addition to measured (proved) reserves, about 46 percent of the undiscovered resources is estimated to be in “unconventional” reservoirs, such as coal beds, “tight” gas sands, and shales. Although large resource estimates are given for these types of accumulations, the main concern is recoverability constrained by price and technology. The in-place resources of coalbed gas in the United States are estimated to be more than 700 TCF (table 1). According to Energy Information Administration (EIA), reserves of coalbed gas in the United States were about 10 TCF and cumulative production was about 1.3 TCF at the end of 1992. However, both production and reserves have increased dramatically from 1989 to the present. The objective of this chapter is to describe the U.S. Geological Survey’s methodology for assessing technically recoverable resources of coalbed gas in the United States. It is emphasized that this methodology is for gas generated, stored, and produced from coal beds and not for gas in adjacent reservoirs that is interpreted to be coal-derived. The computational and economic aspects of the assessment are described elsewhere (Attanasi, this CD-ROM; Crovelli and Balay, this CD-ROM).

There are two environmental concerns related to coalbed gas development - (1) methane emissions related to underground coal mining and (2) water treatment and disposal. The contribution of atmospheric emissions of methane related to underground coal mining is significant in the United States, particularly in the Appalachian (province 067), Black Warrior (province 065), and Illinois (province 064) Basins. However, its development has been hindered by two problems: (1) ownership of the gas (coal versus gas) and (2) conflicts between activities of coalbed gas development and coal mining. In Virginia, legislation was passed in 1990 that reduced the obstacle created by the uncertainty of gas ownership. As a result of this legislation, as many as 465 wells were producing coalbed gas at the end of 1993. The continued development of coalbed gas in these regions would result in significant economic and environmental benefits (Kruger, 1994). One aspect of the assessment is the evaluation of coalbed gas recovery in the underground coal-mining areas of the Eastern United States.

Water is commonly produced from coalbed gas wells, especially during the early stages of production. The volume of water produced from an individual coalbed gas well is generally much higher than that produced from other types of oil and gas wells. Although the total amount produced from all coalbed gas wells is relatively small at present, as compared to all oil and gas wells, the amount will grow if coalbed gas is determined to be a sustainable energy source. The treatment and disposal of this produced water is not only an environmental concern, but they also affect the economics of development. Environmentally acceptable options for water disposal can vary from inexpensive methods, such as discharge into streams, to more costly alternatives, such as underground injection and surface discharge after treatment. This assessment will consider the rates of water production in assessing the recoverable resource potential of coalbed gas.

CHARACTER OF COALBED GAS ACCUMULATIONS

Coal beds have unique characteristics that are different from all other types of rocks from which hydrocarbons are generated and produced. These characteristics must be considered when assessing their recoverable resource base and are briefly discussed below. Many of these characteristics are illustrated in figure 1 and are described in more detail in Diamond (1993), Kaiser (1993a), McElhiney and others (1993), Palmer and others (1993), Paul and Young (1993), Rice and others (1993), and Young and Paul (1993).

GEOLOGIC CHARACTERISTICS

1. Large amounts of gas are generated from coal during the coalification process by both biogenic and thermogenic processes. The yield is probably in the range of 150 to 200 cm^3/g of coal.

2. Coalbed gases are variable in their composition. In addition to methane, these gases can contain significant amounts of heavier hydrocarbons, carbon dioxide, and (or) nitrogen. Thus, they are referred to as coalbed gas, not coalbed methane. Coalbeds can also generate and sometimes produce liquid hydrocarbons, which are characterized by high pour points and can cause production problems.

3. In coal beds, most of the gas is sorbed as a monomolecular layer on internal surfaces. Because coal has large internal surface areas, it has the ability to sorb large amounts of gas and can hold much more gas than the same rock volume in a conventional reservoir.

4. Gas contents of coal generally increase with rank, depth, and reservoir pressure. Coal beds are commonly fully saturated with gas; that is, they contain as much gas as they are able to store. In some cases, the coal matrix may be undersaturated relative to its adsorptive capacity, which can result from natural causes or human-related activities.

5. Coal beds are characterized by heterogeneity in both their distribution and composition. This heterogeneity strongly affects the reservoir- and source-rock characteristics, as well as aquifer characteristics, of the individual coal beds.

6. Coalbed gas accumulations are widespread and commonly extend across basins. However, the factors that affect the generation and accumulation of coalbed gas are variable within these widespread accumulations.

7. Permeability is essentially nonexistent in the matrix of coal, but it is developed in the fracture system, which is referred to as the cleat system. Cleats generally form a rectilinear set of fractures referred to as face (dominant) and butt (subordinate) cleats (fig. 2). The factors which control the permeability of cleats are frequency, connectivity, and aperture width. These factors are controlled by bed thickness, coal quality and rank, tectonic deformation, and stress.

8. In general, permeability decreases with increasing depth of burial (fig. 3) and is not well developed in areas of considerable structural deformation, such as the Cahaba Basin and Tertiary basins of western Washington. In addition, coals are

commonly aquifers because the fracture systems are better developed in coals than in other lithologies.

9. The cleat system is generally 100 percent water saturated prior to and during the early stages of gas and water production. The sources of the water are: (1) original water (inherent moisture), (2) water of meteoric origin, and (3) water from adjacent aquifers. However, cleats may occasionally be gas saturated above the water table in folded areas (fig. 1), such as those in the northern Appalachian, Arkoma, and Powder River Basins, or in areas of very low permeability.

10. Coalbed reservoirs are commonly abnormally pressured (higher or lower than hydrostatic pressure). The causes of overpressuring are: (1) artesian conditions and high permeability, (2) active hydrocarbon generation and low permeability, and (3) preservation of original pressure in isolated reservoirs. Underpressuring is the result of: (1) low permeability and (2) cooling, uplift, and erosion.

PRODUCTION CHARACTERISTICS

1. Coalbed gas accumulations are widespread and are characterized by large in-place resources. Although most wells will encounter gas in a widespread coalbed gas accumulation, some wells will be uneconomic because of low gas- or high water- production rates. In addition, production will be highly variable, even within a single play, because of the heterogeneous nature of coal beds.

2. Coalbed gas production is controlled by: (1) desorption, (2) diffusion, and (3) two-phase flow of gas and water (fig. 4). Because gas is sorbed on the matrix of the coal, reservoir pressure must be reduced to initiate the desorption process. This reduction is usually accomplished by dewatering the coal beds. Diffusion is the process whereby the desorbed gas is transported from the matrix to the cleat system, driven by a concentration gradient. Once the gas diffuses to the coal cleats, it flows by Darcy flow in conjunction with mobile water to the wellbore along a pressure gradient and according to a gas-water relative permeability relation. If the cleat system is fully gas saturated, only single-phase flow of gas occurs.

3. The effects of desorption, diffusion, and Darcy flow generally result in a distinctive production history for coalbed gas wells, as illustrated by figure 5. In the early dewatering stages of production, large amounts of water are produced along with small amounts of gas until sufficient water is produced to allow for

larger amounts of gas to desorb from the matrix and to flow through the cleats to the wellbore. During the stable production stage, the quantities of gas increase as the quantities of water decrease. This production during the stable production stage is commonly referred to as "negative or reverse decline," which distinguishes coalbed gas production from that of other types of reservoirs. Finally, in the later stages of production, the amount of gas gradually declines and water production remains low.

4. Coalbed gas recovery is strongly affected by gas content, permeability, and the adsorption isotherm, a measure of the maximum amount of gas that a coal can sorb. Higher gas contents result in greater in-place values and per-well gas recoveries. Higher permeability results in increased production of both gas and water. With increased permeability, maximum gas flow rates increase in magnitude early in the production history, which results in a higher per-well ultimate recovery. Coals are said to be fully saturated with respect to their adsorptive capacity for gas if the desorption and initial reservoir pressures are the same (fig. 6). If coals are fully saturated, both gas and water are produced as depressurization takes place. However, if the coal matrix is undersaturated with respect to its gas storage capacity (fig. 6), significant pressure drawdown at the wellbore must occur before methane is desorbed. Only water is generally produced during this depressurization stage.

5. Water is commonly produced from coalbed gas wells, especially during the early stages of production (fig. 5). Water production is usually required to reduce reservoir pressure and initiate gas desorption. Water production is variable and is controlled by factors such as permeability, cleat porosity, ground-water flow, and position of the water table. Water disposal poses a major environmental concern in the development of coalbed gas and has a strong effect on the economics of development.

6. Coalbed gas can be produced over a range of pressures, but production is generally highest in areas of artesian overpressuring.

7. Interference between coalbed wells is commonly beneficial for gas production. With decreased well spacing, the increased dewatering process results in more rapid pressure depletion and desorption of gas from the coal matrix.

10. Different types of completion and stimulation methods are used for coalbed gas wells. In underground mining areas, the types of wells used to recover

coalbed gas are: (1) vertical wells drilled from the surface in advance of mining, (2) gob wells drilled from the surface to above the coal bed prior to mining and gas is produced from the fractured zone caused by the collapse of strata surrounding the mined-out coal bed, (3) horizontal boreholes drilled from inside the mine to degasify the coal bed to be mined, and (4) cross-measure boreholes drilled from inside the mine to degasify the surrounding strata. Vertical wells are mostly used for coalbed gas recovery in areas not being mined for coal. These wells commonly require stimulation or special completion techniques, such as under-reaming, open-hole cavitation, and (or) hydraulic fracturing.

ASSESSMENT OF IN-PLACE COALBED GAS RESOURCES

In-place estimates of coalbed gas have been made for most of the major coal-bearing provinces in the United States, including those in which recoverable estimates were made (table 1). The exceptions are the Forest City Basin and Cherokee Platform of the Midcontinent region. The method of determining gas in-place is to multiply the coal tonnage by the gas content (Kelso and Kelafant, 1989). Coal tonnage is the product of the coal thickness, area, and coal density. Coal thickness and areal extent are usually determined from isopach maps. These maps should be used in conjunction with overburden and rank maps so that tonnages can be calculated in reference to these two variables, which strongly affect gas content. The density of coal is the mass of coal per unit volume expressed in tons per acre-foot and varies with the rank of the coal and differences in ash content (Wood and others, 1983).

Although gas content can be determined in several ways, the most common method is by direct measurement of fresh core or drill-cutting samples retrieved from a well during drilling (Rice and others, 1993). This direct method measures three components-desorbed gas, residual gas, and lost gas. Gas content measurements should be normalized to standard temperature and pressure conditions and adjusted to an ash-free basis. Because limited gas-content measurements are usually available for many provinces, gas-content plots are usually made relating gas content to factors such as rank, depth, and reservoir pressure. Gas contents can then be estimated in areas where no measurements are available.

Coalbed gas accumulations are usually widespread, and the in-place estimates are generally very large. Although these large in-place numbers are commonly reported, they only provide an upper limit of the resource and should not be used as a reference in making reliable estimates of recoverable resources.

ASSESSMENT OF POTENTIAL ADDITIONS TO RESERVES OF COALBED GAS

INTRODUCTION

Recoverable resources of coalbed gas, like conventional hydrocarbon resources, are assessed by play analysis. For conventional hydrocarbons that occur in discrete accumulations (fields), plays are defined as a collection of accumulations (discovered and undiscovered), which are interpreted to have common geologic elements resulting in hydrocarbon accumulation, such as reservoir and source rock, trapping conditions, and migration pathways. Recoverable conventional resources are determined by estimating the number and sizes of these undiscovered accumulations, using the distribution of discovered fields as a guide (see Gautier and others, this volume). There is generally a wide range of field sizes in any one play, and small fields are more plentiful than large fields.

In contrast, coalbed gas occurs in widespread accumulations, and plays are areas within these accumulations where similar conditions exist for the generation, accumulation, and recovery of the gas. Although the gas accumulation is widespread, the recovery is highly variable from well to well within a single play. As a result, the assessment of recoverable resources of coalbed gas results from the estimation of the number and distribution of estimated ultimate recoveries (EUR) of untested wells within a play. The variability of EUR's for individual wells within a coalbed gas play is analogous to that of field sizes for conventional hydrocarbon resources.

The procedure is similar, in part, to that developed for "continuous-type" oil and gas accumulations without hydrodynamic influences (i.e., "tight" gas sands and shale gas) (Schmoker and others, this volume).

NOMENCLATURE

Several terms are explained below that are important for the assessment of recoverable coalbed gas resources using play analysis.

Cell. A cell is a subdivision of a coalbed gas play. The area or size of a cell (acres or mi^2) is generally equal to the coalbed gas well spacing authorized by the State regulatory agency at the time of the assessment. Most coalbed wells within a play are capable of producing gas. A productive cell has at least one well with reported production. A hypothetical play has no productive cells. A nonproductive cell contains at least one well that evaluated the coal beds, but production was not reported. In most cases, a well drilled through the coal beds to a deeper objective does not evaluate the coalbed gas potential. In an untested cell, the coalbed gas potential has not been evaluated by a well. The number of untested cells in a coalbed gas play equals the total number of cells minus the number of cells, both productive and nonproductive, in which the coalbed gas has been properly evaluated by a well within the cell.

Success ratio. The fraction (values of 0-1.0) of untested cells in a coalbed gas play that is anticipated to produce gas. The success ratio multiplied by the number of untested cells is equal to the number of potentially productive, untested cells in a coalbed gas play.

Probability distribution of estimated ultimate recoveries (EUR) for potentially productive, untested cells. The probability distribution of EUR's, expressed in millions of cubic feet of gas (MMCF), is judged to be representative of the potentially productive, untested cells within a play. This distribution is commonly distinguished from the EUR probability distribution for cells that are already productive in the play.

Play probability. The probability (values of 0 - 1.0) that one or more of the untested cells in the play will produce at least the minimum EUR (100th fractile) estimated for cells within the play.

PROCEDURE

The geological and engineering approach to the coalbed gas assessment is described below. The steps are generally presented in the order in which they were performed. The data form that was filled out for each coalbed gas play for which undiscovered, recoverable coalbed gas resources were assessed is attached as table 2.

1. Play definition and description

As a first step, plays were defined, described, and outlined within widespread coalbed gas accumulations. Coalbed gas plays are defined as areas where conditions were similar for the generation, accumulation, and recovery of gas. Factors that control these conditions include, but are not limited to: thickness, heterogeneity, depth, and composition of coal, seals, gas content, hydrocarbon composition (gas and liquids), permeability, pressure regime, structural setting (folds, faults, joints, cleats), hydrology (ground-water flow, and quantity and quality of water), and conventional trapping mechanisms, such as structure. Each play is commonly characterized by a single and unique play probability, success ratio, and EUR probability distribution for potentially productive, untested cells. In addition, plays are generally characterized by distinct water-production rates.

The plays that were assessed for recoverable coalbed gas resources are described and outlined elsewhere (Rice, Young, and Paul, this CD-ROM). The number of plays within an accumulation was commonly controlled by data availability. For example, only one basin-wide play was defined in the Forest City Basin of the Midcontinent region where data pertaining to coalbed gas potential were limited. In contrast, the San Juan and Black Warrior basins, which are extensively developed for coalbed gas, have three and four plays, respectively. In general, all coal seams with gas potential in a basin are grouped together, and plays are defined by changes taking place in a group of coals laterally and not vertically. The only basin where plays were defined on the basis of different stratigraphic coal-bearing interval is the Greater Green River Basin. However, it is recognized that different coal seams commonly have contrasting reservoir properties, but data are generally not available to address their productivity for coalbed gas.

Recoverable coalbed gas resources are interpreted to generally extend from depths of about 500 to 6,000 ft below the surface as illustrated by figure 1. As a result, plays were commonly defined within these depth ranges. At shallower depths, gas contents are usually too low for commercial production. At greater depths, permeability is too low to sustain commercial flow rates, in spite of higher gas contents. To further elaborate, permeability is strongly related to effective stress and depth as determined by laboratory and well-test data (McKee and others, 1986, 1988). In general, permeability decreases with depth (fig. 3) and commercial production has generally been at depths of less than 6,000 ft. However, some areas of enhanced permeability may be present below 6,000 ft resulting from structural enhancement, low stress, and (or) dry coal (Kuuskraa and Wyman, 1993). The 6,000 ft depth cutoff greatly affects the recoverable resources of coalbed gas in several basins within the Rocky Mountain area, namely the Piceance, Uinta, Wind River, and Greater Green River. Several of these basins have very large in-place resources, and the recoverable resource number was greatly reduced by this depth decision.

2. Data compilation

Additional data were compiled and recorded for each play to assist in both the geological/engineering, computational, and economic assessments. These data include:

a. Median depth and depth limits of coal in potentially productive, untested cells.

b. Average and maximum net thickness of potentially productive coal and average number of seams.

c. Average thickness of coal-bearing interval.

d. Water quality and method of treatment and disposal.

e. Gas quality

f. Possible production of liquid hydrocarbons.

g. Presence of active underground mines and (or) mined-out areas.

h. Compression requirements

i. Well-completion techniques

j. Analog plays

3. Reservoir simulation

Reservoir simulation is the process of using computer modeling to estimate production, usually from a well or a field (Paul, 1990). As an aid in estimating the undiscovered, recoverable resources of coalbed gas, simulation was used to forecast EUR's and gas and water production rates for undrilled wells in many of the coalbed gas plays. This forecasting was only done for plays in which geologic, engineering, and production data were available. Reservoir simulation was used for several reasons. First, coalbed gas accumulations are in the early stages of development, and long-term production histories for wells are generally not available. Second, other methods, such as decline curve analysis and material balance, are not adequate for expressing the complex movement of gas and water in coal by desorption, diffusion, and Darcy flow. Finally, reservoir simulation is an economical method of forecasting production, which might otherwise only be evaluated by the drilling and production of wells.

The simulator used for this study was COMETPC 3-D (Sawyer and others, 1990), a two-phase, finite-difference model based on the nonequilibrium, pseudo-steady-state formulation described by King and others (1986). COMETPC 3-D has been validated by comparison with black-oil and other coalbed models (Paul and others, 1990). The simulator has been used in many studies, including those to determine the effects of coalbed reservoir properties and completion strategy on well performance in the Black Warrior and San Juan Basins (Paul and Young, 1993; Young and Paul, 1993).

The data commonly required for reservoir simulation are listed in table 3. As might be expected, many of these data are not available, particularly those for evaluating undrilled well locations, which are the emphasis of this study. However, the reservoir simulator, with the assistance of geological and engineering judgement, can be used to assess the sensitivity of well performance to data uncertainties. With parametric or sensitivity analysis, ranges of reservoir properties for which no data have been measured or that are uncertain can be established, which provides a basis for forecasting future gas production.

Prior to initiating the reservoir simulation, geologic and engineering data were collected for each play from publically available sources and private companies. Gas and water production data for representative wells in each play were obtained from Petroleum Information Corporation's production database (Petro-ROM Production Data), State oil- and gas- agencies, and private companies. The data were then reviewed and analyzed in order to prepare an initial list of data suitable for input to the COMETPC 3-D simulator. An example of the input data compiled for the Pennsylvanian Mary Lee coal group of the Pottsville Formation is shown in table 4.

Some of the input data represent estimates. To resolve some of the data uncertainty, particularly for key reservoir parameters like gas content and cleat permeability, actual well production was compared to that predicted by the simulator for two or three wells selected from each play. This process is known as "history matching" because the initial data estimates commonly must be adjusted to obtain simulated results characteristic of actual well performance. Through such history matching, a prototype or "typical" well for each play was established, and reservoir input data were defined with a greater degree of certainty. The reservoir and operational data for the Mary Lee coal group example (table 4) were refined in such a fashion.

The wells selected for history matching, however, do not necessarily characterize the well performance that can be expected from untested cells, which were the focus of this study. To address this contingency, sensitivity simulations were performed to estimate the range in forecasted gas recovery as a function of variations from the "typical" well profile in several key reservoir properties. Ranges in key properties were specifically defined in order to characterize the differences in reservoir conditions that are likely to be encountered as operators attempt to establish commercial production in less developed or undrilled areas of the play. For example, both cleat permeability and coal depth (which was related to variations in initial reservoir pressure and gas content) were varied in order to evaluate nine different producing scenarios for undrilled well locations within the Mary Lee coal group, Black Warrior Basin (table 5).

To estimate the full range of EUR's that might be anticipated from undrilled well locations, including the typical well, about twelve 25-year production forecasts were generated for most plays. For each of these forecast simulations, gas and water production rates and EUR's were reported on both a "per-well" and "per-foot-of- coal" basis. Production results per well reflect completion of the entire coal thickness considered to be represent the average for the play, whereas the per-foot-of- coal results allow production levels to be adjusted to account for changes in coal thicknesses as a function of location within each play and(or) to adjust for the completion of additional coal seams that are not currently producing.

Although operating parameters, such as well spacing and fracture half-length, are also important, they were generally not among the variables used in the sensitivity forecasts. Most plays were evaluated using vertical wellbores, where completion techniques varied between natural open-hole without stimulation, open-hole cavitation, or cased and fracture stimulated with a single fracture half-length value assigned to the entire play. In underground mining areas of the Appalachian and Black Warrior Basins, long-term production forecasts were generated for both vertical and gob wells. Simulated well operation used either a bottom-hole pressure schedule or a constant water pump rate specified as input to the simulator. The operating conditions determined to be appropriate for a particular play were based on experience and knowledge of well operations in the producing part of the play.

4. Estimation of number of untested cells

Technically recoverable resources of coalbed gas in a play will be developed in wells that have a spacing authorized by the State regulatory agency. For this assessment, the present-day authorized spacing was considered to be the size of cells. The authorized spacing, and thus the cell size, may be smaller in the future, but this change was generally not addressed. Wells at different spacings will have distinct EUR's and EUR probability distributions. In some cases, the authorized well spacing within one play may change across a State border. This is the case for basins such as the Greater Green River and Appalachian Basin. In these cases, one cell size was usually maintained for the entire play, usually the one for which data were available for reservoir simulation. If a play was being assessed by EUR information from an analog play, then the cell size of the analog was used for the play being assessed. The total number of cells in a coalbed gas play is equal to the area of the play divided by the cell size.

A cell may have been evaluated by drilling. A cell is not considered to be properly evaluated for coalbed gas potential unless the coal beds were the main objective of drilling: that is, the well was completed in the coal. A properly evaluated cell is either productive or nonproductive of coalbed gas. The number of untested cells equals the total number of cells minus the number of both productive and unproductive cells.

The number of untested cells can be affected by the uncertainties of outlining play boundaries and in determining the number of properly evaluated cells. For example, the decision was made to generally limit the recoverability of coalbed gas to depths between 500 and 6,000 ft below the surface. However, there will probably be localized cases where production will extend beyond those limits. The same imprecision occurs for determining the number of wells that have evaluated the coal beds. For example, many older wells in the Cherokee Platform of southeast Kansas have been recompleted in the coal seams, but the recompletions have not been reported. In addition, many wells are completed in the coal-bearing interval, but it is sometimes difficult to determine if the target was the coal beds or adjacent sandstones.

This uncertainty in the number of untested cells in a coalbed gas play is expressed by giving a range in the possible number of untested cells-median, minimum, and maximum. The computational model is designed to treat the number of untested cells as a probability distribution.

5. Estimation of success ratio

The success ratio for productive cells in a coalbed gas play was subjectively estimated by evaluating the geologic factors controlling productivity. Some of the factors considered were thickness and rank of coal, gas content, permeability, and structure. In the computational model, the product of the success ratio and number of untested cells is equal to the number of potentially productive, untested cells projected for a play.

6. Establishment of EUR probability distribution for potentially productive, untested cells

Reservoir simulation was actually a first step in establishing a EUR probability distribution for potentially productive, untested cells in a coalbed gas play. From that task, a range of EUR's for untested wells in a coalbed gas play was calculated. These EUR's were based on coal properties considered to be representative of untested cells in the play and not those of producing wells. These forecasted EUR's were made for untested cells with a typical coal thickness and also on a per-foot-of-coal basis.

The next step was to determine the probability distribution of these EUR's. Because the development of coalbed gas is in the early stages and is mostly confined to two basins (Black Warrior and San Juan), information was generally not available from existing wells to serve as a guide. Even if an EUR probability distribution was available for existing wells, it would probably not be representative of the undrilled wells.

The EUR distribution for coalbed gas wells was assumed to be lognormal, as suggested by several lines of evidence. First, initial gas potentials and maximum annual gas production for the peak producing year for all Fruitland coalbed wells have a lognormal distribution for the entire San Juan Basin. This distribution is also true for wells from the overpressured and underpressured parts of the basin plotted separately (Kaiser and others, 1991). Second, the average daily production rates at six-month intervals during the first three years of production for coalbed gas wells from different plays in both the San Juan and Black Warrior Basins have a lognormal distribution. Although both sets of data are from early stages of production, they indicate that the EUR's may have a similar distribution. Finally, the EUR's of wells from other types of "unconventional" reservoirs, such as tight gas sands and shale gas, have a lognormal distribution (Schmoker, this volume).

To establish the probability distribution, seven fractiles (100th, 95th, 75th, 50th, 25th, 5th, and 0th) of EUR values were provided for the computational model, and a lognormal probability distribution was assumed. The 50th fractile was determined by: (1) selecting the EUR on a per-foot-of-coal basis for the properties that were considered to be representative of a typical undrilled well in the play, and (2) multiplying this number by the average net thickness of potentially productive coal in the play. As a means estimating the other fractiles, the EUR on a per-foot-of- coal basis for the 10th fractile was chosen using a simulation run with very good coal characteristics. This EUR value was then multiplied by the coal thickness close to the maximum net thickness of all potentially productive coal seams in the play. The EUR for the other fractiles was then estimated from a probability plot using the 50th and 10th fractiles as a guide.

It should be pointed out that, within a single well, the EUR on a per-foot-of- coal basis may be different for coal seams that are stacked vertically and separated from each other. For example, in the Black Warrior Basin, coal beds in the Black Creek, Mary Lee, and Pratt coal groups, have different properties, and, thus, the EUR's on a per-foot-of-coal basis vary. Further, these differences are not strictly the result of depth of burial. As a result, the EUR's of a play were determined by using different EUR's for coal seams within each group. However, data are generally not available for different seams and a uniform EUR on a per-foot-of-coal basis is assumed for all coal seams within a play.

For plays in which reservoir simulation was not done, analog plays were identified in the same basins or another basin that had similar geologic and engineering conditions, resulting in the generation, accumulation, and production of coalbed gas. Next, the simulated EUR on a per-foot-of-coal basis of the analog was scaled based on geological judgments. These adjusted EUR's were then multiplied by coal thicknesses in the assessed play to arrive at the values for 50th and 10th fractiles. The probability plot was again used for estimating the other fractiles.

7. Risk appraisal

The probability was assessed that one or more of the untested cells in the play will produce at least the minimum EUR (100th fractile) estimated for cells within the play. A value of 1.0 indicates geologic certainty that at least the minimum amount of production will occur, whereas lower values suggest risk of obtaining that value. The computational model used the play probability as a factor in calculating the unconditional play potential.

For the Piceance Basin Igneous Intrusion Play (2057), the method of estimating EUR probability distributions for potentially productive, untested cells was not used. For this play, the probability distribution (minimum-100th fractile, median-50th fractile, and maximum-0th fractile) of potential reserves for the entire play area was estimated.

CONCLUSIONS

Coalbed gas is a long recognized, but largely undeveloped energy resource that has the potential of making significant contributions to the Nation's natural-gas resource base. Although large in-place resource numbers have been estimated, they are not considered to form the basis for making reliable estimates of recoverable resources. An important part of the 1995 National hydrocarbon assessment is a well-documented evaluation of the technically recoverable resources of coalbed gas reserves in the United States.

Two environmental concerns are related to the development of coalbed gas and also involve economics. First, large amounts of methane, a potent greenhouse gas, are emitted from underground coal mines, a prevalent problem in the Eastern region. This gas can be recovered before, during, and after mining, which will mitigate the environmental concerns and result in economic benefits. Second, large amounts of water are commonly produced with coalbed gas. This water can be treated and disposed of in an environmentally acceptable manner. However, the methods are sometimes very costly--this might hinder the development of coalbed gas in some areas. This assessment addressed both of these environmental issues, including the impact of economics.

The assessment of technically recoverable coalbed gas resources was done by play analysis. Plays are areas within widespread, commonly basin-wide accumulations that have similar conditions controlling the generation, accumulation, and production of coalbed gas. Recoverable coalbed gas resources are postulated to occur generally between present-day depths of 500 to 6,000 ft because of gas contents and permeability. These depths limits have the effect of greatly reducing the availability of large in-place resources for recovery in several Rocky Mountain basins, such as the Piceance and Greater Green River.

The assessment relied on production forecasting by reservoir simulation. By play, a range of EUR's and production rates of both gas and water were projected for undrilled wells and per foot of coal basis. Reservoir simulation requires a variety of geologic and engineering data, which are commonly not available. Some of the input parameters for this reservoir simulation were based on actual data, and some resulted from the judgments of geologists and engineers. The parameters were generally geologic and engineering in nature and not operational, such as well spacing and fracture half-length. The well spacing authorized by the State regulatory agency was used, and projections were generally not made for possible changes in spacing in the future.

For most plays, long-term production from vertical wells, with a variety of completion techniques, was forecasted. In mining areas, production from both vertical and gob wells was modeled. Although gas is recovered from other types of wells in mining areas, such as horizontal and cross-measure, most of the gas will probably be recovered from vertical and gob wells.

A successful program of recompletion and remediation can add significant volumes of coalbed gas in basins, such as the Black Warrior (Kuuskraa and others, 1994). However, these additional quantities are considered as reserve additions and were not evaluated. In addition, this assessment does not take into consideration the use of advanced technology, such as CO_2 and (or) nitrogen injection (Puri and Yee, 1990), which may result in the improved recovery of coalbed gas as compared to conventional pressure-depletion methods.

The EUR's predicted by reservoir simulation were used in conjunction with coal thicknesses to establish an EUR probability distribution for potentially productive, untested cells in each play. Seven fractiles (100th, 95th, 75th, 50th, 25th, 5th, and 0th) were provided for the computational model, and the distribution was assumed to be lognormal. For plays in which no reservoir simulation was performed, EUR's on a per-foot-of-coal basis from analog plays were scaled, and a similar procedure was used.

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Table 1.--In-place coalbed gas resources of the United States.

In-place coalbed gas resources in the conterminous United States. Data from ICF Resources Inc. (1990), National Petroleum Council (1992), Stevens and others (1992). Gloyn and Sommer (1993), Johnson and others (1993), and Kaiser (1993b). If range of values is given, the highest value is reported.

Basin name	TCF
Arkoma	4
Black Warrior	20
Cahaba	2
Central Appalachian	5
Coosa	1
Greater Green River	314
Illinois	21
Northern Appalachian	61
Piceance	103
Powder River	30
Raton	12
Richmond and Deep River	3
San Juan	84
(includes coal from Fruitland and Menefee Formations)	
Uinta	11
Western Washington	24
Wind River	6
Total	701

Table 2.--Data form for assessment of recoverable coalbed gas.

DATA FORM FOR COALBED GAS ASSESSMENT

Province Geologist: _______________ Province Name, No.: ______________________

Date: _________ Play Name, No.: ____

______ Confirmed (production) or _____ Hypothetical (no production)

Play probability (0-1.0) : ___________________

Cells : Cell size: _______ acres; ________ mi^2 (acres/640)

Area of play ____________mi^2 Total no. of cells: __________

No. of productive cells ________ No. of nonproductive cells: _______

No. of untested cells ________ 50th fractile

Minimum possible number of untested cells: _________ 100th fractile

Maximum possible number of untested cells: _________ 0th fractile

Success ratio (0-1.0) __________

EUR probability distribution :

	Min			Median			Max
Fractile:	100th	95th	75th	50th	25th	5th	0th
EUR (MMCF)	_________	_______	_________	__________	__________	__________	__________

Additional information:

Depth (ft) of untested cells: median________; minimum________; maximum_________

Average net thickness (ft) of potentially productive coal: ______________

Maximum net thickness (ft) of potentially productive coal: ______________

Average number of potentially productive coal seams: ________________

Average thickness (ft) of potentially productive coal-bearing interval: _

Water quality: TDS (ppm) ____________

Present method of water treatment (mechanical or chemical) and disposal:

___

Gas quality: C_1 ______ %, C_2+ ______ %, CO_2 _______%, N_2 ______ %, BTU__

Are liquid hydrocarbons produced? ___Yes ___ No Amounts (GOR) and how long:

___

Is there active underground coal mining? ___ Yes ___ No

What seams? ______________________

Mined-out areas __________mi^2 or ____% What seams? _____________________

Is compression needed for transmission? ___ Yes ___ No

Are coalbed gas wells generally stimulated in this play? ___ Yes or ___ No

If production data and reservoir simulation are not available, what is the analog play(s)?

Table 3.--Data required for coalbed gas reservoir simulation

Coal depth
Coal thickness
Pressure gradient
Initial reservoir pressure
Initial water (gas) saturation
In situ Langmuir volume
Langmuir pressure
In situ gas content
Desorption pressure
Sorption time
Reservoir temperature
Cleat porosity
Pore volume compressibility
Cleat spacing
Gas gravity
Water viscosity at reservoir conditions
Water formation volume factor
Completion and stimulation practices
Well operation
Well spacing, acres/well
Absolute cleat permeability

Table 4.--Input data for reservoir simulation compiled for Pennsylvanian Mary Lee coal group, Pottsville Formation, Black Warrior Basin.

RESERVOIR PARAMETERS FOR MARY LEE COAL GROUP BLACK WARRIOR BASIN			
	Shallower	**Intermediate**	**Deeper**
Coal Depth, feet	1,000	2,200	3,100
Coal Thickness, feet	6	9	7
Pressure Gradient, psi/ft	0.40	0.43	0.43
Initial Reservoir Pressure, psia	415	961	1,348
Initial Water (Gas) Saturation, %	100 (0)	100 (0)	100 (0)
In Situ Langmuir Volume, scf/ton[2]	731	731	731
Langmuir Pressure, psia	837	837	837
In Situ Gas Content, scf/ton[2]	218	352	406
Desorption Pressure, psia[b]	356	777	1,046
Sorption Time, days	10	10	10
Reservoir Temperature, ¡F	75	87	96
Cleat Porosity, %	2	2	1
Pore Volume Compressibility, 10^{-6} psi^{-1}	250	250	250
Cleat Spacing, inches	0.2	0.2	0.2
Gas Gravity	0.57	0.6	0.6
Water Viscosity at Reservoir Conditions, cp	0.923	0.793	0.720
Water Formation Volume Factor, RB/STB	1.01	1.01	1.01
Well Stimulation [c]	Fracture Half-Length of 20 ft		
Well Operation	50 bpd Constant Pump Rate with 20 psia BHP_{min}		
Well Spacing, acres/well	80	80	80
Absolute Cleat Permeability, md	20, 30, 40	5, 10, 25	0.5, 1, 2

a In situ conditions include correction for ash and moisture of about 15%

b Assumes high volatile bituminous coal that is 90% saturated relative to it's full adsorptive capacity

c Assumes infinite conductivity fracture half-length (x_f)

Table 5.--Production scenarios for Pennsylvanian Mary Lee coal group, Pottsville Formation, Black Warrior Basin.

BLACK WARRIOR SENSITIVITY SIMULATIONS VARIATIONS IN FORECASTED 25-YEAR WELL PERFORMANCE FOR MARY LEE COAL GROUP								
Case No.	Cleat Perme-ability (md)	Cleat Porosity (%)	IGIP [a] (MMcf/ Well)	Gas Recovery		IWIP [b] (Mbbls/ Well)	Water Recovery	
				MMcf/ Well	% IGIP		Mbbls/ Well	% IWIP
Shallower Depth Gas Content = 218 scf/ton at 1,000 ft coal depth (415 psia)								
BMWLSh20	20	2	184.64	143.84	77.9	73.8	32.5	44.0
BMWLSh30	30	2	184.64	154.82	83.8	73.8	33.7	45.7
BMWLSh40	40	2	184.64	160.40	86.9	73.8	34.1	46.2
Intermediate Depth Gas Content = 352 scf/ton at 2,200 ft coal depth (961 psia)								
BWMLIn05	5	2	446.82	280.61	62.8	110.9	52.8	47.6
BWMLIn10	10	2	446.82	344.36	77.1	110.9	57.4	51.8
BWMLIn25	25	2	446.82	396.36	88.7	110.9	61.3	55.3
Deep Depth Gas Content = 406 scf/ton at 3,100 ft coal depth (1,348 psia)								
BWMLDppt	0.5	1	405.1	78.24	19.3	43.2	17.4	40.3
BWMLDp01	1	1	405.1	142.98	35.3	43.2	20.6	47.7
BWMLDp02	2	1	405.1	213.91	52.8	43.2	23.3	53.9

[a] Initial gas-in-place

[b] Initial water-in-place

FIGURES

Figure 1 Schematic diagram showing regional geologic setting of coalbed gas accumulation. Coal beds above water table are commonly gas saturated. Coal beds below water table are generally water saturated. Coal beds in tightly folded areas have increased fracturing and may have increased permeability. Gas in coal beds below a depth of 6,000 ft is probably not economically recoverable.

Figure 2. Sketch showing relation between face and butt cleats in coal and carbonaceous shale. The frequency of cleats is generally higher in coal than in carbonaceous shale. From Rice and others (1993).

Figure 3. Permeability versus depth plot for coal beds in the Black Warrior, Piceance, and San Juan Basins. From McKee and others (1986).

Figure 4. Diagram illustrating movement of methane by desorption, diffusion, and Darcy flow within coal. Modified from Kuuskraa and Brandenburg (1989).

Figure 5. Typical production schedule of coalbed gas well showing relative volumes of methane and water with time. From Kuuskraa and Brandenburg (1989).

Figure 6. Sorption isotherm showing adsorbed gas content as a function of reservoir pressure at a constant temperature for a fully saturated (A) and undersaturated (B) coal. Heavy line indicates the maximum amount of gas that can be adsorbed at a given reservoir pressure. Modified from McElhiney and others (1993).

TABLES